EPA

UNDERGROUND INJECTION CONTROL PROGRAM

PERMIT

PREPARED: July 2011

Permit No. WY22180-08827

Class II Enhanced Oil Recovery Injection Well

Tribal C-41
Fremont County, WY

Issued To

Marathon Oil Company

1501 Stampede Avenue
P.O. Box 2690
Cody, WY 82414

Part I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this Permit,

Marathon Oil Company 1501 Stampede Avenue P.O. Box 2690 Cody, WY 82414

is authorized to construct and to operate the following Class II injection well or wells:

Tribal C-41 2170 ft FNL and 668 ft FWL, SWNW S29, T4N, R1W Fremont County, WY

EPA regulates the injection of fluids into injection wells so that injection does not endanger underground sources of drinking water (USDWs). EPA UIC Permit conditions are based on authorities set forth at 40 CFR Parts 144 and 146, and address potential impacts to USDWs.

Under 40 CFR Part 144, Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences are not discussed in this document. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. (40 CFR §144.35) An EPA UIC Permit may be issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR §144.39, 144.40 and 144.41, and may be reviewed at least once every five (5) years to determine if action is required under 40 CFR §144.36(a).

This Permit is issued for the life of the well(s) unless modified, revoked and reissued, or terminated under 40 CFR §144.39 or 144.40. This EPA Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for a UIC Program is delegated to an Indian Tribe or State. Upon the effective date of delegation, reports, notifications, questions and other correspondence should be directed to the Indian Tribe or State Director.

Issue Date: JUL 15 2011 Effective Date JUL 15 2011

Stephen S. Tuber
Assistant Regional Administrator*
Office of Partnerships and Regulatory Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, injection tubing, and packer.

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. Casing and Cement.

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. Injection Tubing and Packer.

Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices.

The Permittee shall install and maintain in good operating condition:

(a) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and

(b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C:

  (i) on the injection tubing; and

  (ii) on the tubing-casing annulus (TCA); and

(c) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) specified in APPENDIX C is reached at the wellhead; and

(d) a non-resettable cumulative volume recorder attached to the injection line.

4. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

5. Postponement of Construction or Conversion

The Permittee shall complete well construction within one year of the Effective Date of the Permit, or in the case of an Area Permit within one year of Authorization of the additional well. Authorization to construct and operate shall expire if the well has not been constructed within one year of the Effective Date of the Permit or Authorization and the Permit may be terminated under 40 CFR 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be reissued.

6. Workovers and Alterations

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA within sixty (60) days of completion of the activity.

A successful demonstration of Part I MI is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

MI is an abbreviation for the term Mechanical Integrity.

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

(a) There is no significant leak in the casing, tubing, or packer (Part I); and

(b) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (Part II).

1. Demonstration of Mechanical Integrity (MI).

The operator shall demonstrate MI prior to commencing injection and periodically thereafter. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both internal (Part I) and external (Part II) MI as described above. The conditions present at this well site warrant the methods and frequency required in Appendix B of this Permit.

In addition to these regularly scheduled demonstrations of MI, the operator shall demonstrate internal (Part I) MI after any workover which affects the tubing, packer or casing.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. Mechanical Integrity Test Methods and Criteria

EPA-approved methods shall be used to demonstrate mechanical integrity. Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" are available from EPA and will be provided upon request.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

3. Notification Prior to Testing.

The Permittee shall notify the Director at least seven calendar days prior to any mechanical integrity test unless the mechanical integrity test is conducted after a well construction, well conversion, or a well rework, in which case any prior notice is sufficient. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. Loss of Mechanical Integrity.

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the TCA, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

Section C. WELL OPERATION
INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. Requirements Prior to Commencing Injection.
Well injection, including for new wells authorized by an Area Permit under 40 CFR 144.33 (c), may commence only after all well construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until construction is complete, and

(a) The Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-10 or 7520-12; all applicable logging and testing requirements of this Permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity pursuant to 40 CFR 146.8 and Part II Section B of this Permit has been demonstrated; and

(i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or

(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in Paragraph 1a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.
Injection is permitted only within the approved injection interval, listed in APPENDIX C. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6.

3. Injection Pressure Limitation

(a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C. Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs. In no case shall injection pressure cause the movement of injection or formation fluids into a USDW.

(b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permitee may be required to conduct a step rate injection test or other suitable test to provide information for determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be by modification of this Permit and APPENDIX C.

4. *Injection Volume Limitation.*
Injection volume is limited to the total volume specified in APPENDIX C.

5. *Injection Fluid Limitation.*
Injected fluids are limited to those identified in 40 CFR 144.6(b)(2) as fluids used for enhanced recovery of oil or natural gas, including those which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, pursuant to 40 CFR 144.6(b). Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are NOT approved for injection. This well is NOT approved for commercial brine injection, industrial waste fluid disposal or injection of hazardous waste as defined by CFR 40 Part 261. The Permittee shall provide a listing of the sources of injected fluids in accordance with the reporting requirements in Part II Section D Paragraph 4 and APPENDIX D of this Permit.

6. *Tubing-Casing Annulus (TCA)*
The tubing-casing annulus (TCA) shall be filled with water treated with a corrosion inhibitor, or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi.

If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. *Monitoring Parameters, Frequency, Records and Reports.*
Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

(a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;

(b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;

(c) the analytical techniques or methods used for analysis.

2. *Monitoring Methods.*

(a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

(b) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.

(c) Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.

(d) Pressures are to be measured in pounds per square inch (psi).

(e) Fluid volumes are to be measured in standard oil field barrels (bbl).

(f) Fluid rates are to be measured in barrels per day (bbl/day).

3. Records Retention.

(a) Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.

(b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

4. Annual Reports.

Whether the well is operating or not, the Permittee shall submit an Annual Report to the Director that summarizes the results of the monitoring required by Part II Section D and APPENDIX D.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. EPA Form 7520-11 may be copied and shall be used to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Section E. PLUGGING AND ABANDONMENT

1. *Notification of Well Abandonment, Conversion or Closure.*

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. *Well Plugging Requirements*

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water, and in accordance with 40 CFR 146.10 and other applicable Federal, State or local law or regulations. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

3. *Approved Plugging and Abandonment Plan.*

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. *Forty Five (45) Day Notice of Plugging and Abandonment.*

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abanonment plan.

5. *Plugging and Abandonment Report.*

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or

(b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. *Inactive Wells.*

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

(a) Provides written notice to the Director;

(b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and

(c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR 142 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other Federal, State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

Section B. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance, or Termination.

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions.

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class II injection well to a non-Class II well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit.

Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. *Permittee Change of Address.*

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. *Construction Changes, Workovers, Logging and Testing Data*

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workovers, logging , or test data to EPA within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part III, Section F of this Permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

Section C. SEVERABILITY

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

Section D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section E. GENERAL PERMIT REQUIREMENTS

1. *Duty to Comply.*

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. Duty to Reapply.

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR 144.37 the Permittee must apply for a new permit prior to the expiration date.

3. Need to Halt or Reduce Activity Not a Defense.

It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate.

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance.

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Permit Actions.

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. Property Rights.

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. Duty to Provide Information.

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. Inspection and Entry.

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,

(d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements.

All applications, reports or other information submitted to the Director shall be signed and certified according to 40 CFR 144.32. This section explains the requirements for persons duly authorized to sign documents, and provides wording for required certification.

11. Reporting Requirements.

(a) Planned changes. The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.

(b) Anticipated noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(c) Monitoring Reports. Monitoring results shall be reported at the intervals specified in this Permit.

(d) Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than 30 days following each schedule date.

(e) Twenty-four hour reporting. The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

(i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or

(ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

(g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency.

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

See diagram.

Top of Cement = surface

SURFACE CASING
Hole Size: 12 1/4 inch
Casing Size: 9 5/8 inch; 36 #
Casing Depth: 809 feet
Cement: 0 - 809 feet w/355 sxs

PRODUCTION CASING
Hole Size: 8 1/2 inch
Casing Size: 7 inch; 26 #
Casing Depth: 7177 feet
Cement: 0 - 7177 feet w/890 sxs

PERFORATIONS
Phosphoria: 6,800 feet - 6,814 feet; 6,922 feet - 6,928 feet
Tensleep: 7,008 feet - 7,020 feet; 7,026 feet - 7,044 feet

2 7/8 inch Tubing: 6,742 feet or within 100 feet of the top perforation

3-3 Packer: 6,743 feet or within 100 feet of the top perforation

Total Depth: 7,177 feet

Plug Back Total Depth: 7,128 feet

Fill: 7,047 feet - 7,128 feet

All depths are in Kelly Bushings

Ground Level = 5,770 feet

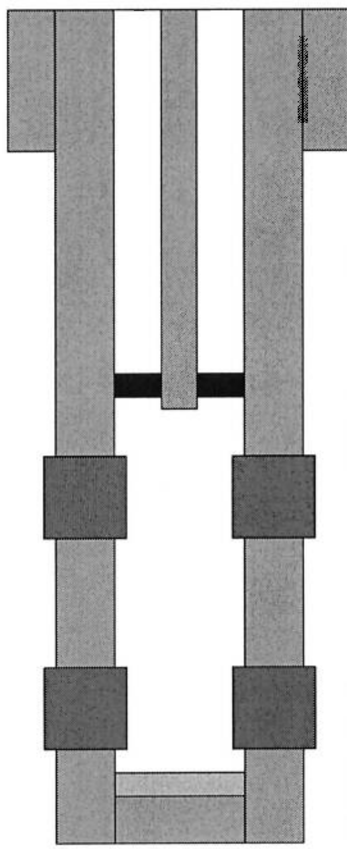
Kelly Bushings = 5,790 feet

TRIBAL C-41 WELL
WELL CONSTRUCTION DIAGRAM

668 ft. FWL & 2170 ft. FNL
SW/4 NW/4, Section 29
Township 4 North, Range 1 West
Steamboat Butte Field
Fremont County, Wyoming
API No. 49-013-22018

Formation Tops. ft.
Quaternary: 0
Frontier: 2932
Mowry: 3579
Muddy: 4172
Dakota: 4337
Fuson: 4410
Morrison: 4640
Sundance: 4859
Gypsum Springs: 5050
Nugget: 5335
Dinwoody: 6385
Phosphoria: 6785
Tensleep: 7000
Amsden: 7474

Elevation: 5790 ft. KB and 5770 ft. GL



Surface casing
9 5/8 inch casing
12 ¼ inch hole
0 – 809 ft. casing
0 – 809 ft. cemented interval

Top of Cement = surface
(depth from application)

Tubing = 6742 ft. or w/in 100 ft of top perf.
Packer = 6743 ft. or w/in 100 ft of top perf.

Phosphoria perforations: 6800-6814 ft.,
6922-6928 ft.

Production casing
7 inch casing
8 ½ inch hole
0 – 7177 ft. casing
0 – 7177 ft. cemented interval

Tensleep perforations: 7008-7020 ft.;
7026-7044 ft.

Fill 7048 – 7128 ft.
Plug Back Total Depth = 7128 ft.
Total Depth = 7177 ft.

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APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Logs.

Logs will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

WELL NAME: Tribal C-41

TYPE OF LOG	DATE DUE
TEMP	Shall be performed upon receipt of a written request from the EPA and within 90 and 180 days during the second approved 180 days limited authorization to inject timeframe
RATS	Shall be performed within 90 and 180 days during the first approved 180 days limited authorization to inject timeframe

Tests.

Tests will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

WELL NAME: Tribal C-41

TYPE OF TEST	DATE DUE
Standard Annulus Pressure	Prior to authorization to inject and at least once every five (5) years after the last successful demonstration of Part I Mechanical Integrity.
Pore Pressure	Prior to receiving authorization to begin injection

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

	MAXIMUM ALLOWED INJECTION PRESSURE (psi)	
WELL NAME	ZONE 1 (Upper)	ZONE 2 (Lower)
Tribal C-41	1,655	1,655

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

WELL NAME: Tribal C-41

	APPROVED INJECTION INTERVAL (KB, ft)		FRACTURE GRADIENT
FORMATION NAME	TOP	BOTTOM	(psi/ft)
Phosphoria	6,785.00 -	7,000.00	0.680
Tensleep	7,000.00 -	7,474.00	0.680

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

There is no limitation on the number of barrels per day (bbls/day) of water that shall be injected into this well, provided further that in no case shall injection pressure exceed that limit shown in Appendix C.

APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section D, for detailed requirements for observing, recording, and reporting these parameters.

OBSERVE MONTHLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS	
OBSERVE AND RECORD	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)

ANNUALLY	
ANALYZE	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid specific conductivity
	Injected fluid pH

ANNUALLY	
REPORT	Each month's maximum and averaged injection pressures (psig)
	Each month's maximum and minimum annulus pressure(s) (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis
	Sources of all fluids injected during the year

In addition to these items, additional Logging and Testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B - LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT REQUIREMENTS

See diagram.

The Plugging and Abandonment (P & A) Plan presented below is considered to be protective of all USDWs. The P & A Plan is incorporated into this permit and is binding on the Permittee.

After receiving approval from the appropriate authorities, the permitted injection well will be plugged and abandoned in accordance with the following Plug and Abandonment Plan.

PLUG #1- ISOLATION OF THE INJECTION ZONE AND UPPER CONFINING ZONE (DINWOODY)
Plug #1A
Set a 20 feet cement balanced plug above the cement retainer between the depths of 6,680 feet to 6,700 feet inside the 7 inch casing.

Cement Retainer
Set a Cement Retainer between the depths of 6,700 feet to 6,704 feet or at least 100 feet above the top Phosphoria Formation perforation (6,800 ft).

Plug #1B
Squeeze cement into the perforations and set a 424 feet cement plug between the depths of 6,704 feet to 7,128 feet inside the 7 inch casing.

PLUG #2 - ISOLATION OF THE MOWRY SHALE FORMATION
Set a 200 feet cement balanced plug between the depths of 4,000 feet to 4,200 feet inside the 7 inch casing.

PLUG #3 - ISOLATION OF THE CODY SHALE FORMATION
Set a 200 feet cement balanced plug between the depths of 1,300 feet to 1,500 feet inside the 7 inch casing.

PLUG #4 - ISOLATION OF THE SURFACE CASING AND SHOE
Set a 819 feet cement balance plug between the depths of 0 to 819 feet inside the 7 inch casing.

Cut off the wellhead below the surface casing. Install a Plug and Abandonment marker.

Note: All identified depths are approximate. The permittee shall set cement within +/- 10 feet of the identified depth locations. Cemented areas using balanced plugs shall be tagged. Class III or similar type cement shall be used to Plug and Abandon the

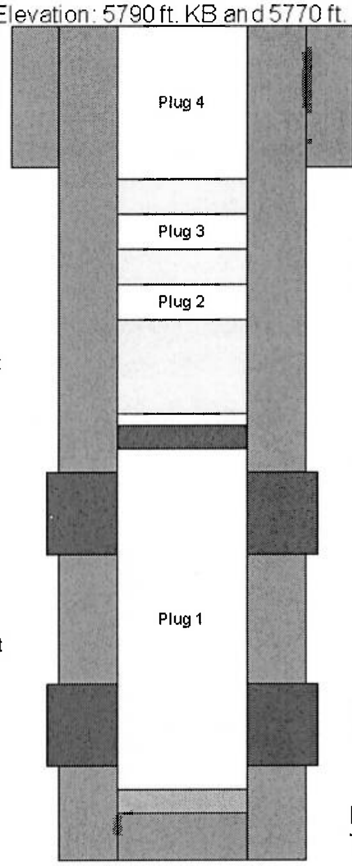
Tribal C-41 well.

Water-based muds, or brines containing a plugging gel, with a density of at least 9.2 lb/gal should be used during plugging operations, and should remain between plugs in the well after cement plug placement.

TRIBAL C-41 WELL
WELL PLUG AND ABANDONMENT DIAGRAM

668 ft. FWL & 2170 ft. FNL
SW/4 NW/4, Section 29
Township 4 North, Range 1 West
Steamboat Butte Field
Fremont County, Wyoming
API No. 49-013-22018

Elevation: 5790 ft. KB and 5770 ft. GL



Surface casing
9 5/8 inch casing
12 ¼ inch hole
0 – 809 ft. casing
0 – 809 ft. cemented interval

Formation Tops, ft.
Quaternary: 0
Frontier: 2932
Mowry: 3579
Muddy: 4172
Dakota: 4337
Fuson: 4410
Morrison: 4640
Sundance: 4859
Gypsum Springs: 5050
Nugget: 5335
Dinwoody: 6385
Phosphoria: 6785
Tensleep: 7000
Amsden: 7474

Plug #4: 0 - 819 ft

Plug #3: 1300 ft – 1500 ft

Plug #2: 4000 ft – 4200 ft

Top of Cement = surface
(depth from application)

Tubing = 6742 ft.
Packer = 6743 ft.

Phosphoria perforations: 6800-6814 ft.; 6922-6928 ft.

Production casing
7 inch casing
8 ½ inch hole
0 – 7177 ft. casing
0 – 7177 ft. cemented interval

Plug #1
Cement Retainer @ 6700 ft – 6704 ft
Plug 1A : 6680 ft – 6700 ft
Plug 1B: 6704 ft – 7128 ft

Tensleep perforations: 7008-7020 ft.; 7026-7044 ft.

Fill 7048 – 7128 ft.
Plug Back Total Depth = 7128 ft.
Total Depth = 7177 ft.

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APPENDIX F

CORRECTIVE ACTION REQUIREMENTS

No corrective action is deemed necessary for this project.

STATEMENT OF BASIS

MARATHON OIL COMPANY
TRIBAL C-41
FREMONT COUNTY, WY

EPA PERMIT NO. WY22180-08827

CONTACT: Linda Bowling
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-GW
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6254

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR 144.36(a).

PART I. General Information and Description of Facility

Marathon Oil Company
1501 Stampede Avenue
P.O. Box 2690
Cody, WY 82414

on

May 20, 2010

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

Tribal C-41
2170 ft FNL and 668 ft FWL, SWNW S29, T4N, R1W
Fremont County, WY

Regulations specific to the Wind River Indian Reservation injection wells are found at 40 CFR 147 Subpart ZZ. The well is located on lands held in trust by the United States for the Northern Arapaho and Eastern Shoshone Tribes. The well is located on Wind River Indian Reservation land and is thus in "Indian country" as defined at 18 U.S.C. 1151. EPA has not approved the State of Wyoming to implement the SDWA UIC program in Indian country. EPA directly implements the SDWA UIC program on Indian country lands within the State of Wyoming.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

The Tribal C-41 is an active Phosphoria and Tensleep Formation production well. Marathon Oil Company proposes converting the well from an active production well to a Phosphoria and Tensleep Formation injection well to support an ongoing secondary recovery project in the Steamboat Butte Field.

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Northern Arapaho Indian Tribe, the Eastern Shoshone Tribe or the State of Wyoming unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

TABLE 1.1 WELL STATUS / DATE OF OPERATION		
NEW WELLS		
Well Name	**Well Status**	**Date of Operation**
Tribal C-41	New	N/A

PART II. Permit Considerations (40 CFR 146.24)

Hydrogeologic Setting

Geologic Setting (TABLE 2.1)

The depths for each formation has been obtained from the Tribal C-41 application, the permittees spreadsheet, and data obtained from the Wyoming Oil and Gas Conservation Commission's database. The classification of the formations and total dissolved solids content data has been obtained from the resource document, Water Resources Research Institute, Volume IV-A, Occurrence and Characteristics of Ground Water In The Wind River Basin, Wyoming.

TABLE 2.1
GEOLOGIC SETTING
Tribal C-41

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Quarternary Sands	0	60	2,430	
Cody Shale	60	2,932	1,750 - 2,430	Shale, fissile, calcareous and bentonitic. Grades upward to thin bedded, fine grain sandstone with interbedded calcareous shale.
Frontier	2,932	3,579	4,383 - 7,630	Alternating sequence of sandstone and shale
Mowry Shale	3,579	4,172		Shale, bentonite, and claystone
Muddy	4,172	4,197	7,292 - 7,553	Sandstone, siltstone, and shale
Thermopolis	4,197	4,337		Shale
Dakota	4,337	4,410	6,080	Sand
Fuson	4,410	4,640		Shale
Morrison	4,640	4,859		sandstone, claystone and shale
Sundance	4,859	5,050		Sandstone, shale, limestone
Gypsum Springs	5,050	5,335		shale, limestone, dolomite, gypsum, siltstone
Nugget	5,335	6,385		sandstone
Dinwoody	6,385	6,785		dolomite, siltstone, sandstone, and limestone
Phosphoria	6,785	7,000		limestone, dolomite, siltstone, sandstone
Tensleep	7,000	7,474		sandstone, limestone and dolomite
Amsden	7,474	7,717		shale, dolomite, limestone and sandstone

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

The applicant proposes to inject into the Phosphoria and Tensleep Formations. The Phosphoria Formation is approximately 216 feet (ft.) thick. The Tensleep Formation is approximately 177 ft. thick. Both formations have been exempted in the proposed location and are listed under Title 40 Code of Federal Regulations Section 147.2554 for Class II Oil and Gas operations.

TABLE 2.2
INJECTION ZONES
Tribal C-41

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Phosphoria	6,785	7,000		0.680		N/A
Tensleep	7,000	7,474		0.680		N/A

*** C - Currently Exempted**
E - Previously Exempted
P - Proposed Exemption
N/A - Not Applicable

Confining Zone(s) (TABLE 2.3)
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3.

Confining Zones are based upon well information obtained from the Wyoming Oil and Gas Conservation Commission's database and data submitted in the permittee's permit application package and supplemental spreadsheet. The confining zones are also based upon information presented in the resource document, Water Resources Research Institute, Volume IV-A, Occurrence and Characteristics of Groundwater in the Wind River Basin, Wyoming.

TABLE 2.3
CONFINING ZONES
Tribal C-41

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Cody Shale	Shale, fissile, calcareous and bentonitic. Grades upward to thin bedded, fine grain sandstone with interbedded calcareous shale.	60	2,932
Mowry Shale	Shale, bentonite, and claystone	3,579	4,172
Thermopolis	Shale	4,197	4,337
Fuson	Shale	4,410	4,640
Morrison	sandstone, claystone and shale	4,640	4,859
Gypsum Springs	shale, limestone, dolomite, gypsum, siltstone	5,050	5,335
Dinwoody	dolomite, siltstone, sandstone, and limestone	6,385	6,785
Amsden	shale, dolomite, limestone and sandstone	7,474	7,717

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)

Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

The list of Underground Sources of Drinking Water (USDWs) are based upon information provided in Marathon's Permit application for the Tribal C-41 Permit Application and information submitted in the resource document, Water Resources Research Institute, Volume IV-A, Occurrence and Characteristics of Groundwater in the Wind River Basin, Wyoming.

TABLE 2.4

UNDERGROUND SOURCES OF DRINKING WATER (USDW)

Tribal C-41

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Quarternary Sands		0	60	2,430
Frontier	Alternating sequence of sandstone and shale	2,932	3,579	4,383 - 7,630
Muddy	Sandstone, siltstone, and shale	4,172	4,197	7,292 - 7,553
Dakota	Sand	4,337	4,410	6,080
Nugget	sandstone	5,335	6,385	

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1

WELL CONSTRUCTION REQUIREMENTS

Tribal C-41

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	12.25	9.63	0 - 809	0 - 809
Longstring	8.50	7.00	0 - 7,177	0 - 7,177

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)

The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of Part II (External) mechanical integrity.

A Cement Bond Log (CBL), dated December 28, 2001, has been submitted for the Tribal C-41 well. The CBL was reviewed to determine if adequate cement exists within the confining zone and through the remainder of the well. The permittee did not provide or log the upper portion of the upper Dinwoody confining zone. The portions of the confining zone which were log did not display the needed 33 ft. of continuous 80% bond cement behind pipe in the confining zone. Based upon a February 9, 2011 email, Marathon requests to run a Radioactive Tracer Survey rather than to re-run a CBL for the well to demonstrate the presence of adequate cement behind pipe.

Tubing and Packer

Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

The tubing and packer shall be set at a depth at or below 100 feet of the top perforation.

Tubing-Casing Annulus (TCA)

The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

The annulus fluid for the Tribal C-41 well will be fresh water treated with a corrosion inhibitor and oxygen scavenger. The Cortron R-2264 is the corrosion inhibitor which will be used. It is composed of cyclic amine derivatives, methanol, and sulfur dioxide. The Cortron RU-142 is the oxygen scavenger which will be used. It is composed chemicals such as cobalt chloride.

Monitoring Devices

The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
Tribal C1-2X	Injector	No	7,440	3,245	No
Tribal C-14	Injector	No	7,167	2,444	No
Tribal C-31	Injector	No	7,403	1,950	No
Tribal C-36	Producer	No	7,321	0	No
Tribal C-39	Producer	No	7,179	0	No

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well.

Area Of Review

Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For Area Permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

The ¼ mile area of review is considered to be adequate due to the depth of the injection zone relative to overlying USDWs and geological characteristics of the proposed injection zone. There are three additional injection wells within a ¼ mile radius of the proposed Tribal C-41 injection well. Three wells will inject into the Phosphoria Formation and four wells will inject into the Tensleep Formation within a ¼ mile radius. All wells will serve as a part of an enhanced recovery operation which will keep fluids within the ¼ mile area of review.

The 1/4 mile area of review is considered to be adequate due to the depth of the injection zone relative to overlying USDWs and geological characteristics of the proposed injection zone.

Within a mile of the subject well there are no permitted water wells. Water wells within a radius of 5 miles of the Tribal C-41 Well consist of the Wind River Formation wells less than 500 feet deep. Based on information obtained from the Wyoming State Engineers Database the following locations, miscellaneous- stock- irrigation or drinking water wells, and range of depths for completed wells are listed below:

- Township 5 North, Range 2 West, none
- Township 5 North, Range 1 West, none
- Township 5 North, Range 1 East, none
- Township 4 North, Range 2 West, 1 well, completed to a depth of 200 ft or shallower
- Township 4 North, Range 1 West, none
- Township 4 North, Range 1 East, none
- Township 3 North, Range 2 West, 19 wells, completed to a depth of 520 ft or shallower

- Township 3 North, Range 1 West, 29 wells, completed to a depth of 392 ft or shallower and 1 well completed to a depth of 6400 ft.

There is 1 irrigation groundwater well permit, Water Rights Number P25624.0W, which is completed to a depth of 6400 ft. in either the Muddy, Phosphoria or Tensleep Formation. It is located approximately 2.5 to 3 miles away and is a collection point and pit associated with biproduct water from 2 oil and gas wells. This irrigation groundwater well permit is expired and several production wells exist between this irrigation well and the proposed injection well.

- Township 3 North, Range 1 East, 69 wells, completed to a depth of 657 feet or shallower

Data for Drinking Water Wells was obtained from the Wyoming State Engineers Office E-Permit database in February 2011

Corrective Action Plan

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the permittee.

No Corrective Action is required because the top of cement in the five wells extends into and above the upper confining Dinwoody Formation and through the lower confining Amsden Formation, in cases where the well is completed into the lower confining zone. The applicant has identified wells within a ½ mile radius. All four injection wells in the area of review will operate below the formation's fracture pressure.

The following injections wells shall operate within or below the fracture gradients approved by EPA on August 12, 1997:

- Tribal C-41, Phosphoria and Tensleep Injector, maximum allowed injection pressure (MAIP) is 1655 psi

- Tribal C1-2X, Phosphoria and Tensleep Injector, MAIP is 1050 psi

- Tribal C-14, Phosphoria and Tensleep Injector, MAIP is 1794 psi

- Tribal C-31, Tensleep Injector, MAIP is 1879 psi

PART V. Well Operation Requirements (40 CFR 146.23)

TABLE 5.1 INJECTION ZONE PRESSURES Tribal C-41			
Formation Name	**Depth Used to Calculate MAIP (ft)**	**Fracture Gradient (psi/ft)**	**Initial MAIP (psi)**
Phosphoria	6,785	0.680	1,655
Tensleep	6,785	0.680	1,655

Approved Injection Fluid

The approved injection fluid is limited to Class II injection well fluids pursuant to 40 CFR § 144.6(b). For disposal wells injecting water brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, the fluid may be commingled and the well used to inject other Class II wastes such as drilling fluids and spent well completion, treatment and stimulation fluid. Injection of non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes, and vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste, is prohibited.

The source of water for injection into the Tribal C-41 well will be a mixture of produced water from all producing formations in the Steamboat Butte Field. The water quality of the source water ranges between 3,187 mg/l to 4,710 mg/l.

The applicant will only be allowed to inject fluids produced from oil and gas operations listed above. The applicant shall request approval from the EPA prior to injecting fluids from other sources or other types of fluids such as fracking fluids. The applicant shall identify the constituents in all fracking fluids.

Injection Pressure Limitation

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit.

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

The initial maximum allowable injection pressure (MAIP) is calculated to be 1655 psi. This value has been calculated based upon the following:

Fracture gradient = 0.68 psi/ft
The fracture gradient is less than the fracture gradients approved in EPA's letter, "Allowable Maximum Injection Pressures, Steamboat Butte Fied dated August 12,1997. The approved fracture gradient for the Phosphoria is 0.77 psi/ft and the Tensleep Formation is 0.70 psi/ft.

Specific Gravity = 1.007
This is the highest specific gravity submitted with the water quality data. This information was submitted in Exhibit 6 of the application. This data has been collected from samples obtained from the C1 Injection Plant Discharge.

D is an abbreviation for Depth of the top of the Phosphoria Formation = 6785 ft

No Step Rate test will be required to verify the calculated MAIP. The operator plans to use one injection tube to emplace source water into the Phosphoria and Tensleep Formations. Therefore the most conservative value, fracture gradient, has been used in the calculation to ensure that an exceedence of fracture pressure for either formation is not encountered.

Injection Volume Limitation

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

Mechanical Integrity (40 CFR 146.8)

An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

The applicant will submit the results of a Standard Annulus Pressure Test prior to receiving authorization to injection and every five years thereafter, to fulfill the Part I (Internal) Mechanical Integrity Test requirements. A Cement Bond Log dated 12/28/2001 did not demonstrate the presence of 33 ft of 80% bond cement in the portion of the confining zone included in the log submittal. Therefore, the applicant will be required to run a Radioactive Tracer Survey (RTS) between ninety (90) and one hundred eighty (180) days after receiving a limited authorization to inject. An RTS is required to demonstrate the adequacy of the cement present in the well. Should the RTS fail to address data needs the applicant may either be required to perform additional logging with an RTS or another logging method. The applicant may also be required to fulfill Part II (External) Mechanical Integrity Test requirements with the use of an approved method:

temperature log, noise log, oxygen activation log.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA annually as part of the Annual Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, annulus pressure, monthly injection flow rate and cumulative fluid volume. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix E of the Permit.

The injection well plugging and abandonment plan described in Appendix E is considered to be adequate for protecting overlying USDWs. The permittee also is required to comply with other applicable federal state and local plugging regulations. The plugging and abandonment plan isolates the injection zone, confining zone, surface shoe and surface.

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

A demonstration of Financial Responsibility in the amount of $52,500 has been provided.

The Director may revise the amount required, and may require the permittee to obtain and provide updated estimates of costs for plugging the well according to the approved Plugging and Abandonment Plan.

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Evidence of continuing financial responsibility is required to be submitted to the Director annually.

PART IX. Considerations Under Federal Law (40 CFR § 144.4)

EPA has determined that issuance of Permit Number WY22180-08827 for the Tribal C-41 injection well is in compliance with the laws, regulations, and orders described at 40 C.F.R. § 144.4, including the National Historic Preservation Act (NHPA) and the Endangered Species Act (ESA).